BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2020-263-E

Cherokee County Cogeneration Partners, LLC	)
	)
Complainant,	)
	)
v.	)
	)
Duke Energy Progress, LLC and Duke Energy Carolinas, LLC,	)
	)
Respondents.	)

PRE-FILED REBUTTAL TESTIMONY OF
KURT G. STRUNK
ON BEHALF OF
CHEROKEE COUNTY COGENERATION PARTNERS, LLC

JUNE 14, 2021

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I. INTRODUCTION

1. Q. Please state your name, title, and business address.

A. My name is Kurt G. Strunk. My business address is 1166 Avenue of the Americas, New York, New York, 10036.

2. Q. Are you the same Kurt G. Strunk who prepared Direct Testimony on behalf of Cherokee County Cogeneration Partners, LLC in this matter?

A. Yes. I prepared Direct Testimony on behalf of Cherokee County Cogeneration Partners, LLC ("Cherokee") filed with this Commission on May 3, 2021.

3. Q. What is the purpose of your rebuttal testimony?

A. My testimony responds to the statements of various employees of Duke Energy Carolinas ("DEC"), who present opinions and factual evidence in their pre-filed testimony dated May 24, 2021. Specifically, my testimony responds to:

- The general characterizations made by the DEC witnesses of DEC's October 2018 offer to Cherokee, particularly their contention that the rate offered to Cherokee "was based on then-current inputs in a manner that was fundamentally consistent with the Commission's directives to the Companies in its recent avoided cost proceeding," was "not discriminatory to QFs," and was consistent with FERC's "implementing regulations." (Freund, p. 6, 7, 10)
- The statements of DEC witness Mr. Freund that my estimated PPA rate is grossly over-simplified, inappropriate, and stale relative to DEC's avoided costs in October 2018. (Freund, p. 3, 12, 13)
- The claim of DEC witness Mr. Snider that the date of a QF's Legally Enforceable Obligation ("LEO") should align with the initial date of delivery of capacity and/or energy by the QF to the offtaking utility under that LEO. (Snider, p.13)

- The misstatement of my testimony by DEC witness Mr. Keen regarding the purported need of Cherokee for "higher rates." (Keen, p. 9)
- The misinterpretation of my testimony by DEC witness Ms. Bowman as it concerns the financing of Qualified Facilities ("QFs") under the Public Utility Regulatory Policies Act ("PURPA"). (Bowman, p. 25)

4. Q. **What are your primary conclusions?**

A. My analysis of the evidence advanced by DEC leads me to the following conclusions on each of the DEC claims listed above:

- The factual circumstances do not support DEC's claim that the utility acted in good faith to strike a deal with Cherokee and applied the guidance from this Commission and the FERC in its dealings with Cherokee. My rebuttal testimony establishes that the DEC rate offered to Cherokee in October 2018 was not reflective of the most recent Commission Order on avoided costs and did not reasonably follow FERC's implementing regulations.
- Mr. Freund's estimate of an appropriate avoided-cost PPA rate as of October 2018 is based on assumptions that were not approved by the Commission for use in QF pricing at the time Cherokee communicated its commitment to sell Cherokee's capacity and energy to DEC in September 2018.[1] Mr. Freund's criticism that the PPA rate I calculate is inappropriate is without merit. My calculations rely on DEC's *own* avoided cost estimates and Commission-approved avoided cost rates.[2]

[1] See Mr. Freund's Testimony, p. 14.

[2] *Ibid*, p. 3.

- Mr. Snider's novel interpretation that seeks to align the date of a LEO with the first date of delivery to the offtaking utility runs counter to the intent and plain language of PURPA and the implementing regulations.[3] Under Mr. Snider's view, QFs would only establish LEOs once they have begun commercial operation and deliver energy and/or capacity. Under this model, they would not be granted reasonable opportunities to displace utility investment in new capacity.
- Mr. Keen's contention that I testified that Cherokee needed rates that were higher than DEC's avoided cost is false.[4] My testimony includes no such statement. My testimony is that Cherokee was entitled to avoided-cost rates, consistent with FERC's implementing regulations and the guidance of this Commission. My understanding is that Cherokee never sought a rate that was above reasonably forecasted avoided costs for DEC as of September 2018 when Cherokee expressed its commitment of capacity to DEC.
- Ms. Bowman errs in interpreting my testimony to mean that *any* potential QF should be financeable.[5] It is a truism that a QF that is uneconomic relative to the offtaking utility's avoided costs will not be financeable. My testimony simply recognizes that the legal and regulatory framework for QFs under PURPA assures financeability for QFs that are economically viable at avoided-cost rates. PURPA sets the rate payable to QFs at the offtaking utility's avoided cost. It would be unreasonable to expect QFs that are not viable at avoided cost rates to obtain financing.

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[3] See Mr. Snider's Testimony, p. 13.

[4] See Mr. Keen's Testimony, p. 9, 22.

[5] See Ms. Bowman's Testimony, p. 25.

Having reviewed DEC's reply evidence, I continue to support the reasonableness of the conclusions presented in my Direct Testimony. Contrary to the contentions of DEC's witnesses,[6] Duke's October 2018 offer was unreasonable as it did not include compensation for avoided capacity, while DEC was offering avoided capacity cost compensation to other QFs and was itself anticipating adding over 800 megawatts of new capacity during the 2020 to 2026 time frame.[7] Duke's October 2018 offer was also unreasonable because it was not structured to confer the benefits of Cherokee's dispatchability to DEC's customers.

My Direct Testimony established that, given Cherokee's September 2018 commitment to put the Cherokee capacity and energy to DEC, a reasonable avoided-cost PPA rate for Cherokee for a delivery start date of January 1, 2021 is $110 per kW-year, inclusive of compensation for Cherokee's start costs. This rate incorporates the then most recent Commission-approved avoided capacity cost rates and DEC's own avoided energy cost forecast, as conveyed to Cherokee in DEC's October 2018 offer.

As noted, in response to Mr. Snider, I continue to support the economic need for the establishment of a LEO well in advance of the contract delivery date. Building lead time into the process is necessary and appropriate for a Cherokee PPA renewal, just as it is for a yet-to-be-developed QFs. If the Commission were to accept Mr. Snider's recommendation to align LEOs and deliveries, doing so would disadvantage QFs and hinder their ability to displace utility investment. Under Mr. Snider's approach, DEC would rarely if ever find itself

[6] See, for example, Mr. Freund's Testimony, p. 6.

[7] See Duke Energy Carolinas 2018 Integrated Resource Plan, Docket No. 2018-10-E, p. 67, 87.

with insufficient capacity at the time of delivery and thus would not be able to defer any utility investment because the QF contracting process would not incorporate any lead time. Mr. Snider's approach undermines the intent of PURPA and the plain language of the statute and implementing regulations.

II. <u>RESPONSE TO CLAIM THAT DEC'S OCTOBER 2018 OFFER FOLLOWED GUIDANCE FROM FERC AND THIS COMMISSION</u>

5. Q. Please identify those elements of DEC's testimony that you address in this section of your rebuttal.

A. In this section, I respond to DEC's claim that the utility acted in good faith to strike a deal with Cherokee and applied the guidance from this Commission and the FERC in its dealings with Cherokee. Specifically, Mr. Freund contends that the rate offered to Cherokee "was based on then-current inputs in a manner that was fundamentally consistent with the Commission's directives to the Companies in its recent avoided cost proceeding," was "not discriminatory to QFs," and was consistent with FERC's "implementing regulations." (Freund, p. 6, 7, 10) The fact pattern surrounding DEC's October 2018 offer does not support Mr. Freund's position.

6. Q. Why is Mr. Freund's claim not supported by the facts?

A. The facts show that DEC's October 2018 offer: (i) deviated from the guidance in "the Commission's directives to the Companies in its recent avoided cost proceeding," (ii) was discriminatory, and (iii) was not consistent with FERC's implementing regulations.

Before addressing how DEC deviated from the directives in Order 2016-349 and how the offer was discriminatory, I explain how DEC's October 2018 offer did not follow FERC's implementing regulations offered to guide negotiations between offtaking utilities and large QFs. DEC's October 2018 offer deviated from FERC's implementing regulations in several material respects.

- DEC's October 2018 offer ignored the requirement under FERC's implementing regulations that negotiations with large QFs take into account "the ability of the electric utility to dispatch the qualifying facility."[8]
- DEC's October 2018 offer did not reasonably address "the deferral of capacity additions," as required by FERC's implementing regulations.[9]
- DEC's October 2018 did not reasonably address "the reduction of fossil fuel use," as required by FERC's implementing regulations. [10]
- Because DEC's October 2018 offer failed to meet the requirements outlined above, and because it was discriminatory, it resulted in a rate that was not "just and reasonable to the electric consumer of the electric utility and in the public interest," also a requirement of FERC's implementing regulations.[11]

I address each deficiency in turn.

7. Q. Please rebut Mr. Freund's claim that the DEC's October 2018 offer followed the requirement under FERC's implementing regulations that negotiations with large QFs take into account "the ability of the electric utility to dispatch the qualifying facility." [12, 13]

A. DEC's October 2018 offer made no mention of Cherokee's dispatchability and was structured in such a way as to mirror the rates offered to non-dispatchable

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[8] See 18 CFR § 292.304(e)(2)(ii)(A).

[9] *Ibid,* (e)(2)(iii).

[10] *Ibid,* (e)(2)(iii).

[11] *Ibid,* (a)(1)(i).

[12] See Mr. Freund's Testimony, p. 6.

[13] See 18 CFR § 292.304(e)(2)(ii)(A).

solar QFs that have essentially zero dispatch cost, deliver energy intermittently, and cannot be ramped up by DEC in response to load fluctuations. DEC states that its offer was "intended to provide price signals to which Cherokee could respond in accordance with their own economics."[14] Yet these price signals would not allow Cherokee to operate efficiently because they would not allow the dispatch of Cherokee in all appropriate circumstances. Under the October 2018 offer, in the event that Cherokee's dispatch cost exceeded the "price signal" but fell below Duke's avoided costs at the time of delivery, Cherokee would elect not to be dispatched, thereby foreclosing opportunities for DEC to achieve fuel savings. Contrary to Mr. Freund's testimony, DEC's offer did not reasonably address the dispatchability of Cherokee.

DEC's October 2018 offer did not manage gas price risk for the consuming public and would have obligated customers to pay a fixed rate for power from Cherokee irrespective of the level of gas prices. In contrast, under a dispatchable PPA structure, the consuming public pays less when gas prices decline, and if gas prices increase, the output is not must take but can be called upon only when economic. The existing PPA is a dispatchable PPA with dispatch costs implicitly a function of gas prices. Such a structure protects customers from the risks that a fixed-price, must-take QF contract will be out of market. To be most consistent with the implementing regulations, and with the parties' existing contract structure, the October 2018 offer from DEC should have placed dispatch decisions with DEC and left Cherokee indifferent as to dispatch. DEC's October 2018 offer did not do so.

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[14] See DEC response to Cherokee Interrogatory 3.

The Cherokee facility is not a recent addition to the DEC portfolio of resources. DEC has a history of dispatching it accounting for gas price levels and power system conditions. Not accounting for its dispatchability, and not addressing gas price risk in a reasonable manner, meant that DEC's October 2018 did not follow the FERC's implementing regulations.

8. Q. Do DEC's responses to interrogatories further disprove Mr. Freund's claim that the DEC's October 2018 offer followed the requirement under FERC's implementing regulations that negotiations with large QFs take into account "the ability of the electric utility to dispatch the qualifying facility."

A. Yes, in response to Cherokee's Interrogatory 1, DEC provided a MS Excel spreadsheet entitled "Rate calc_Cherokee_Oct 2018 quote_v0.xlsx." That spreadsheet shows how DEC valued the energy from Cherokee during peak and off-peak periods. Nowhere in that valuation did DEC account for Cherokee's dispatchability. Instead, DEC treated the energy from Cherokee as having a fixed profile in peak and off-peak hours. Electric utilities in planning exercises typically apply such profiles to non-dispatchable resources but not to dispatchable ones. DEC's use of a fixed profile to evaluate Cherokee indicates that it was not accounting for Cherokee's dispatchability and instead treating it like a solar QF.

9. Q. Do DEC's responses to interrogatories further reveal how DEC could have taken into account dispatchability in the October 2018 offer and therefore corroborate your rebuttal of Mr. Freund above?

A. Yes, in response to Cherokee's Interrogatory 15, DEC provided a narrative description of how it had developed its February 2021 offer to Cherokee. That narrative description explains the process by which DEC, nearly 18 months after Cherokee put the capacity to DEC, considered the facility's dispatchability.

Specifically, DEC states in its attachment interrogatory response entitled "Cherokee contract capacity price calc (methodology)_02.16.21 v0" :

> The energy value for Cherokee was estimated using the methodology from the standard and large QF tariff pricing development, as established by the SC commission in DEC's last avoided cost proceeding. This involved the simulation of DEC's portfolio of generation resources in a "base case" scenario, and a "change-case" that reflects the addition of an increment of QF capacity to the simulation. **The change-case used for the Cherokee analysis added a QF with the characteristics of the Cherokee resource. Cherokee's VOM and start costs were assumed to equal the current/extended contract pricing. The difference in system production costs between the change-case and base-case represents the energy value of Cherokee.**

10. Q. Why is it important that DEC explicitly simulated the Cherokee resource characteristics in 2021?

A. It is important because it demonstrates that by 2021, at least, DEC was considering Cherokee as a dispatchable resource. It was pursuing a specific analytical technique that allowed DEC to evaluate the value of Cherokee as a dispatchable resource, an analytic technique that DEC had not applied in earlier stages of the negotiation process.

11. Q. Does the contrast between how DEC approached the February 2021 offer and how it approached the October 2018 offer shed light on the deficiencies of the October 2018 offer and undermine Mr. Freund's claim that DEC accounted for dispatchability as required by FERC's implementing regulations?

A. Yes, it does. The evidence advanced by DEC demonstrates that, in February 2021, DEC simulated its generation fleet with and without a resource with Cherokee's characteristics, reflecting Cherokee's dispatchability and the cost to start up the facility.[15] This difference between the with Cherokee case and without Cherokee case established the 2021 forecast of avoided energy costs.

[15] See DEC Responses to Cherokee Interrogatory 15.

In contrast, DEC's evidence confirms that DEC's February 2018 offer to Cherokee contained no such accounting for Cherokee's dispatchability. Rather, DEC confirms in its response to Cherokee Interrogatory 3 that it did not simulate its generation fleet with a resource with Cherokee's operating characteristics, further confirming that it did not properly take into account Cherokee's dispatchability, as required by FERC's implementing regulations.

12. Q. Turning now to Mr. Freund's claim that DEC accounted for the requirement in FERC's implementing regulations that the offtaking utility examine "the deferral of capacity additions," how do you respond? [16, 17]

A. In contrast to Mr. Freund's claim of compliance with these regulations, DEC's October 2018 offer was based on DEC's conclusion that it could not defer any capacity investment during the proposed PPA term. Yet its investment plan included over 800 megawatts of new capacity major investments before 2026. The investment plan included a 402 megawatt open-cycle combustion turbine at Lincoln scheduled to enter into commercial operation in 2024, over 5 years out at the time of DEC's October 2018 offer to Cherokee. (I note that CTs can have a lead time of as little as 2 years before commercial operation.)[18] In this regard, DEC's October 2018 offer is seemingly lacking in its compliance with the PURPA implementing regulations, namely the objective of putting QFs on equal footing with utility capacity investments and allowing reasonable opportunities to displace utility investments in new generation capacity. In addition, as I explain below, DEC's position on capacity compensation in its October 2018

[16] See Mr. Freund's Testimony, p. 6.

[17] See 18 CFR § 292.304(e)(2)(iii).

[18] See Energy Information Administration, "Assumptions to the Annual Energy Outlook 2021: Electricity Market Module," p. 6.

offer is not consistent with the directive given to DEC in Commission Order 2016-349, an Order DEC repeatedly claims it complied with.[19]

13. Q. Please respond to Mr. Freund's claim that DEC accounted for the requirement in FERC's implementing regulations that the offtaking utility account for the "reduction in fossil fuel use" in negotiating rates with large QFs.[20, 21]

A. DEC's October 2018 offer was not structured in a way that would incentivize Cherokee to operate in a way that maximizes opportunities to reduce fossil fuel use. Under the October 2018 offer, in the event that Cherokee's dispatch cost exceeded the fixed contract rate but fell below Duke's avoidable energy costs at the time of delivery, Cherokee would be incentivized not to be dispatched. However, in most such instances, Duke would be able to reduce fossil fuel use by substituting production from Cherokee for production from a higher heat rate resource. In those instances, Cherokee's production could displace energy from resources that are less efficient in converting fossil fuels to electricity and thereby reduce fossil fuel use. The DEC October 2018 offer obstructed the achievement of that objective and did not reasonably follow the FERC's implementing regulations as Mr. Freund contends.

14. Q. Please respond to Mr. Freund's claim that DEC accounted for the requirement in FERC's implementing regulations that rate offered by the offtaking utility be "just and reasonable." [22, 23]

A. DEC's October 2018 offer to Cherokee was not just and reasonable because it did not meet key provisions in the implementing regulations as described above.

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[19] See DEC Responses to Cherokee Interrogatories 3, 6, 8, 12, and 14.

[20] See Mr. Freund's Testimony, p. 6.

[21] See 18 CFR § 292.304(e)(2)(iii).

[22] See Mr. Freund's Testimony, p. 6.

[23] 18 CFR § 292.304(a)(1)(i).

It was also not just and reasonable because it was discriminatory. As I explained in my Direct Testimony, the October 2018 offer to Cherokee DEC was discriminatory because DEC was offering other QFs rates that provided compensation for avoided capacity costs but was not offering that compensation to Cherokee.

15. Q. Please respond to Mr. Freund's claim that DEC's October 2018 offer followed the Commission's guidance in Order 2016-349.

A. Order 2016-349 dated May 12, 2016 in Docket 1995-1192-E established rates for small QFs under the standard offer and provided that rates for large QFs would be negotiated pursuant to FERC's implementing regulations. Although Mr. Freund claims (Freund, p. 6) that DEC's October 2018 offer was "fundamentally consistent" with that Order, it was not.

In Order 2016-349, the Commission approved a settlement whereby the adjudicated outcome from the most recent North Carolina avoided cost proceeding was deemed to be just and reasonable for application in South Carolina. Yet, in adjudicating the outcome in North Carolina, the NCUC had flatly rejected the approach that Mr. Snider presents as DEC's avoided capacity cost methodology. (Snider, p. 22-24) The NCUC held: "It is inappropriate in this docket, when employing the peaker method, to require the inclusion of zeroes for the early years when calculating avoided capacity rates."[24] DEC's October 2018 offer to Cherokee was based upon the assumption – the "inclusion of zeroes for the early years"— that had been rejected by the NCUC and implicitly accepted by this Commission when it deemed the settlement rates just

[24] Order Setting Avoided Cost Input Parameters, North Carolina Utilities Commission Docket No. E-100, Sub 140, December 31, 2014, p. 8.

and reasonable.[25] As such, I find DEC's claim that its methodology followed recent directives from the Commission in Order 2016-349 to be rather stretched.

III. RESPONSE TO MR. FREUND'S ESTIMATED PPA RATE

16. Q. Please identify those elements of DEC's testimony that you address in this section of your rebuttal.

A. In this section, I respond to the statements of DEC witness Mr. Freund that my estimated PPA rate is grossly over-simplified, inappropriate, and stale relative to DEC's avoided costs in October 2018. (Freund, p. 3, 12, 13).

17. Q. How do you respond to Mr. Freund's claim that your analysis is too simple?

A. Mr. Freund's criticism of my analysis is based on the fact that I did not use a production cost model. Yet in order to establish an approximation of the reasonable rate for Cherokee, I did not need to run a production cost model. I relied on the output of DEC's own production cost modeling, reflecting a constrained optimization of its complex electric power grid. Because I use DEC's own numbers for its avoided energy cost as of October 2018, Mr. Freund's criticism is without merit.

18. Q. If you had run a production cost model, do you expect that you would have calculated a higher PPA rate for Cherokee?

A. Yes. As noted, my analysis was based on the DEC September 2018 production cost model results, which DEC used as the basis for its October 2018 offer to Cherokee. As disclosed by DEC in response to interrogatories,[26] its 2018 production cost modeling used to price a PPA for Cherokee did not assess the value of Cherokee's dispatchability. Had I run my own dispatch modeling, that

[25] See Order No. 2016-349, Public Service Commission of South Carolina, Docket No. 1995-1192-E, May 12, 2016. See also *supra*, footnote 24.

[26] See DEC Responses to Cherokee Interrogatories 1 and 3.

modeling would have permitted Cherokee to ramp up and down in response to projected conditions on the power grid. The absence of explicit modeling of Cherokee's actual dispatch flexibility makes my analysis conservative. Incorporating flexibility could only increase the calculated value of Cherokee to the DEC system, all else equal.

19 Q. Mr. Freund says that your estimate of an appropriate avoided cost payment for Cherokee "failed to recognize start cost payments" that DEC makes under the current PPA. How do you respond?

A. Mr. Freund mischaracterizes my analysis. I did not ignore start cost payments. As I stated in my Direct Testimony, the avoided cost PPA rate I calculated of $110 per kW-year was "inclusive of compensation for start costs and Cherokee's fixed operations and maintenance costs."[27] I clarified further in Footnote 8, "[i]f the new PURPA contract were to provide for explicit payment of start costs or fixed operations and maintenance costs, the baseline capacity charge would be reduced accordingly."[28] The plain language of my Direct Testimony disproves Mr. Freund's contention that I fail "to recognize start cost payments"

20. Q. Please address Mr. Freund's claim that your analysis is stale and does not reflect then-current avoided costs. (Freund, p. 13)

A. Mr. Freund's argument, echoed by Mr. Snider, is in essence that by 2018, DEC's next deferrable capacity need was to occur at a future date beyond the term of the PPA.[29] For that reason, these witnesses argue DEC was not obligated to offer Cherokee any capacity compensation.[30]

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[27] Pre-Filed Direct Testimony of Kurt G. Strunk, p. 16.

[28] *Ibid,* footnote 8.

[29] See Mr. Freund's Testimony, p. 14-15.

[30] *Ibid.*

The DEC arguments in this regard are unpersuasive. They are premised on an assumption of zero capacity credit that the NCUC had rejected and that this Commission also implicitly rejected when it allowed the adoption of the North Carolina rates in South Carolina.[31] In this context, it was unreasonable, as of October 2018, to prejudge how such a contentious issue would ultimately be resolved by this Commission in the upcoming avoided cost docket.

It is not uncommon for the host utility's capacity need date, and the relationship to QF capacity pricing, to be subject to debate in adjudicated regulatory proceedings. The topic was hotly debated before this Commission in Docket 2019-186-E.[32] DEC's approach to its Cherokee offer in October 2018 unreasonably ignored the most recent ruling of this Commission in Order 2016-349, while also prejudging the outcome of an upcoming future proceeding.

Although I do not take issue with Mr. Freund's characterization of DEC's 2018 IRP, at the time of the October 2018 Cherokee offer, that 2018 IRP had not yet been approved by the Commission. Furthermore, DEC's stance on which of its over 800 megawatts of new capacity additions in the 2020 to 2026 time frame were and were not avoidable, deferrable or resizable for the purpose of QF avoided capacity compensation was poised to be a contentious subject in the upcoming avoided cost proceeding. It was also possible that the South Carolina Commission would reject Mr. Snider's approach in the same way the NCUC had. It was not appropriate for DEC to prejudge the outcomes of future adjudicated proceedings and offer zero capacity compensation to DEC while

[31] Although prior Commission orders had permitted regulated utilities in South Carolina to apply zero capacity compensation to QFs in periods when the host utility had excess supply, the Commission's decision in Order 2016-349 adopting the NCUC result implicitly went against that principle.

[32] See Order No. 2019-881(A), Public Service Commission of South Carolina, Docket No. 2019-185-E, January 2, 2020, p. 82-89.

offering full capacity compensation to QFs initiating standard offer contracts in late 2018.

21. Q. Mr. Freund makes a reference to a 10-year tolling PPA priced at the time of Cherokee's September 2018 commitment letter to DEC.[33] Do you agree with his analysis of an appropriate 10-year tolling PPA structure, consistent with Cherokee's September 2018 capacity commitment to DEC?

No. Mr. Freund's pricing for the 10-year tolling agreement is not reasonable. His capacity cost compensation is less than a third of what DEC was offering to other QFs at that time under the Commission-approved standard offer. While my $110/kW-year PPA rate is based on DEC's 5-year avoided energy cost forecast, it provides a reasonable floor for a 10-year PPA term, given that Commission-approved QF energy rates for 10-year terms tend to be above those approved for 5-year terms.

22. Q. Is the 10-year tolling PPA pricing as of September 2018 important to Cherokee?

A. Yes. As Mr. Hanson explains in his Rebuttal Testimony, Cherokee is seeking a 10-year tolling PPA priced at the time of its September 2018 capacity commitment to DEC. As such, the appropriate rate for the 10-year term and PPA structure is very relevant.

IV. RESPONSE TO MR. SNIDER ON ALIGNMENT OF THE LEO DATE AND INITIAL CONTRACT DELIVERIES

23. Q. Please identify those elements of DEC's testimony that you address in this section of your rebuttal.

A. In this section, I address Mr. Snider's claim that the LEO date should align with the first date of delivery from the QF to the offtaking utility.[34]

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[33] See Mr. Freund's Testimony, p. 14.

[34] See Mr. Snider's Testimony, p. 13.

24. Q. If the Commission were to agree with Mr. Snider on this point, what would be the practical implications for QFs?

A. In practice, Mr. Snider's recommendation would mean no advance contracting for QFs, which would be discriminatory against QFs and in violation of FERC's PURPA policies.[35] Mr. Snider is arguing that all QFs should have a LEO that is contemporaneous with the initial delivery of energy or capacity under the QF contract. Such a policy is discriminatory against QFs because it removes opportunities for the QFs to displace utility investment. It undermines the implementing regulations and the PURPA statute itself. QFs are supposed to have an option, which only they can choose to exercise, to sell at a forecast avoided cost rate calculated at the date of the LEO. Mr. Snider's proposal modifies the value of that option by putting QF capacity at a disadvantage relative to utility capacity. For Mr. Snider, QFs should not have a right to contract in advance of delivery, but utility new capacity additions can be developed well in advance of delivery.

V. RESPONSE TO MR. KEEN ON THE CLAIM THAT CHEROKEE DEMANDED A HIGHER RATE THAN AVOIDED COST

25. Q. Please identify those elements of DEC's testimony that you address in this section of your rebuttal.

A. In this section, I address Mr. Keen's mischaracterization of my testimony. Mr. Keen claims that I testify Cherokee needs higher rates (*i.e.*, rates above DEC's avoided cost).[36]

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[35] See *Final Rule Regarding the Implementation of Section 210 of the Public Utility Regulatory Policies Act of 1978,* Order No. 69 §292.304, FERC Stats. & Regs.

[36] See Mr. Keen's Testimony, p. 9.

26. Q. Does your Direct Testimony include the claim that Cherokee sought a rate above DEC's avoided cost?

A. No. My Direct Testimony includes no such claim. Mr. Keen is wrong to characterize my testimony in that fashion. I understand, and I believe Cherokee understands, that the only entitlement Cherokee has is to a rate at a forecast avoided cost, with the projections of avoided cost being made based on prevailing conditions as of September 2018, when Cherokee communicated its commitment of the Cherokee capacity to DEC for a forward period beginning January 1, 2021.

VI. RESPONSE TO MS. BOWMAN ON QF FINANCEABILITY

27. Q. Please identify those elements of DEC's testimony that you address in this section of your rebuttal.

A. In this section, I respond to Ms. Bowman's interpretation of my testimony to mean that *all* potential QFs should be financeable.[37]

28. Q. Do you believe there is a fundamental divide as between your opinions and those of Ms. Bowman when it comes to QF financeability?

A. No. It is not my testimony that *all* potential QFs should be financeable. I agree with Ms. Bowman that if QFs are uneconomic relative to the offtaking utility's avoided costs, they will not be financeable. My testimony is simply that the legal and regulatory framework for QFs under PURPA assures financeability for QFs that are economically viable at avoided-cost rates.

29. Q. Does this conclude your pre-filed rebuttal testimony?

A. Yes.

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[37] See Ms. Bowman's Testimony, p. 25.

June 2021

Kurt G. Strunk

BEFORE THE
PUBLIC SERVICE COMMISSION
OF SOUTH CAROLINA
DOCKET NO. 2020-263-E

Cherokee County Cogeneration Partners, LLC Complainant, v. Duke Energy Progress, LLC and Duke Energy Carolinas, LLC, Respondents.	)	**REBUTTAL TESTIMONY OF NATHAN HANSON**

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Nathan Hanson and my business address is 1700 Broadway, 35th Floor New York, NY 10019.

Q. HAVE YOU SUBMITTED TESTIMONY PREVIOUSLY IN THIS PROCEEDING?

A. Yes. I filed Direct Testimony on May 3, 2021.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of this rebuttal testimony is to respond to the testimony of several of the Duke (DEC and DEP) witnesses.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY.

A. Duke has refused to recognize the legally enforceable obligation (LEO) Cherokee created in September of 2018 that required Duke to base its avoided cost projections, including its avoided capacity costs, as of that LEO date. Instead, and contrary to PURPA, Duke offered pricing that not only ignored the LEO date, but had an expiration date, preventing meaningful negotiation. Moreover, Duke's offers and course of dealing overlooked the ongoing relationship between the parties. Despite the fact that Cherokee has been providing its output to DEC for decades, and DEC has dispatched the Cherokee facility at a high volume on economic dispatch for many years, Duke "negotiated" with Cherokee as if it was a brand new, non-dispatchable facility in development with no operational history. Duke has also raised petty arguments and manufactured unnecessary roadblocks that stonewalled negotiations.

Q. DO YOU AGREE WITH MR. KEEN'S CHARACTERIZATIONS OF DUKE'S NEGOTIATIONS WITH CHEROKEE?

A. No. To the extent that Mr. Keen describes the timeline of communications (Keen Direct Exhibit 1), it appears that it roughly matches with our account in terms of dates. However, I certainly would not describe Duke as having engaged in "good faith negotiations" (Keen Direct, p. 4 ll. 15-16) at any point in this process.

Q. WHY DO YOU SAY DUKE HAS NOT ENGAGED WITH CHEROKEE IN GOOD FAITH?

A. While Duke did "respond" to our requests, its refusal to: 1) recognize Cherokee's LEO date and the rights created on that date, 2) acknowledge the history of its relationship with Cherokee and the Facility, or 3) provide support for its proposed rates, have prevented open and meaningful negotiations required by PURPA and the orders of this Commission. PURPA requires that utilities:

- Recognize non-contractual rights that arise as of the date a LEO is transmitted to the utility;
- Provide QFs avoided costs that are calculated based on the utility's projected

avoided costs as of the LEO date for the contract term; and

- Provide QFs with the data needed to confirm the utility's avoided cost calculation.

Q. **HOW HAS DUKE FAILED TO RECOGNIZE CHEROKEE'S AVOIDED COST PRICING RIGHTS ASSOCIATED WITH CHEROKEE'S LEO DATE?**

A. PURPA requires that Duke offer avoided cost calculations based on projections *as of the LEO date* for the period of delivery under the contract. Contrary to the requirements of PURPA, Duke repeatedly failed to provide pricing based on the date of the LEO. Instead, Duke has provided Cherokee firm offers that expire after 60 days if a PPA is not executed within that period. For example, Witness Bowman (Direct, p. 22) states that Duke's avoided cost rates are only good for 60 days, and they are revoked if a PPA is not negotiated within that time period." However, Ms. Bowman fails to cite to any authority that would permit Duke to revoke its avoided cost rates provided in response to a LEO after a period of 60 days. In fact, such a requirement violates PURPA, as the PURPA LEO represents a "stake in the ground" that fixes the date of the calculation. There is no "expiration" or "revocation," as the LEO is intended to protect the QF by locking in the calculation date.

Q. **PLEASE EXPLAIN THE PROBLEMS WITH DUKE'S PRICING PROPOSALS.**

A. PURPA provides that it is the QF's right to have the avoided costs calculated for the delivery period (in Cherokee's case beyond the December 31, 2020 expiration of the current PPA) based on (i) avoided cost rates at the time of delivery or (ii) projections of future avoided costs *as of* the LEO date.[1] The latter option – the QF's ability to

[1] *See* 18 C.F.R. 292.304(d)(1).

established avoided costs as of the LEO date – is designed to protect QFs from precisely the type of actions that Duke has taken here to stall or avoid its PURPA obligations. Contrary to Mr, Keen's testimony (p. 13, ll. 5-8), PURPA does not allow Duke to negate Cherokee's LEO by deeming that "Cherokee's right to the avoided cost rates provided in October 2018" expired according to its arbitrary 60-day timeline, coupled with the fact that Duke refused to provide support for its proposed avoided cost pricing. FERC has repeatedly advised that states cannot require a "utility-executed" contract as a prerequisite for establishment of a LEO, precisely because utilities can (and have) purposefully delayed negotiations or refused to agree to reasonable terms that a QF can accept.[2] If the utility had the ability to control establishment of a LEO, it could delay and obstruct until it no longer had a capacity need.

Such delays are not attributed solely to a complete failure of a utility to tender a contract as Duke suggests (Bowman Direct, p. 20, ll. 7-9); but also in proffering a contract that is not "executable" by the QF because it does not meet PURPA's requirements. As this Commission recognized in its 2019 avoided cost proceedings implementing Act 62, LEOs are intended "to prevent a utility from circumventing the requirement that provides capacity credit for an eligible qualifying facility merely by refusing to enter into a contract with the qualifying facility."[3] Duke acknowledged this in the 2019 avoided cost proceedings,[4] and this Commission recognized the same in stating unequivocally that "[c]ontrolling *or frustrating* the QF to form a LEO is prohibited by

[2] *Id.* (citing Order No. 69).

[3] Order No. 2019-881(A) in Docket Nos. 2019-185-E and 2019-186-E, p. 140.

[4] Order No. 2019-881(A), p. 142 ("…given Witness Levitas' comments regarding conditioning a LEO on an action by the utility (i.e., delivering the System Impact Study Report), the Companies believe it would be more appropriate to instead require the QF to have submitted a signed Facilities Study Agreement to the utility.")

FERC."[5] Here, Duke has obstructed and delayed negotiations, procured additional capacity as though Cherokee did not exist *after* Cherokee told Duke that it intended to sell its capacity to Duke at avoided cost rates pursuant to its rights under PURPA, and now claims it doesn't need capacity because it consciously ignored Cherokee's LEO. This course of action does not evince "good faith."

Q. WHY ARE AVOIDED COST PROJECTIONS AT THE TIME THE LEO WAS FORMED SIGNIFICANT TO CHEROKEE?

A. As explained by Cherokee Witness Strunk, reasonable avoided cost pricing for Cherokee at the time the LEO was formed exceeds the October 2018 offer made by Duke, which should have included a capacity payment. Subsequent offers incorporated updates to the avoided cost forecasts and did not recognize Cherokee's "stake in the ground." It is my understanding that, under PURPA, avoided cost projections must correspond to the time of the LEO in September 2018. Duke's earliest offers failed to recognize that Cherokee could displace utility capacity investment and that Cherokee should be paid for capacity. Duke's subsequent offers ignore the LEO, make no attempt to base avoided cost rate projections at the time the LEO was established, and instead purport to offer avoided cost rates at the time the offer was made.

Q. HOW HAS DUKE FAILED TO ACKNOWLEDGE THE EXISTENCE OF THE LEO?

A. Since we initially contacted Duke with our LEO materials, they have consistently denied that we established a LEO. It is clear under FERC regulations, which must guide this

[5] Order No. 2019-881(A), pp.133-134. (emphasis added). While I understand that Act 62 was directed toward small power producer QFs rather than cogeneration; FERC's requirements for LEOs do not vary based on the type of QF.

Commission's implementation of PURPA, that the formation of a LEO turns on the actions of the QF, *not* the actions of the utility.[6] States cannot abridge this federal right under PURPA. While it is true that states may establish protocols or standardized processes to assist state public service commissions in determining whether a LEO has been formed, federal law invalidates any such state effort that would allow the *utility* to control "whether and when a legally enforceable obligation exists" for the reasons described above.[7]

Q DO YOU AGREE WITH WITNESSES KEEN AND SNIDER THAT CHEROKEE DID NOT FILL OUT THE CORRECT NOTICE OF COMMITMENT (NOC) FORM?

A. No. As a predicate matter, the claim that Cherokee did not fill out the "correct" form (Keen Direct, p. 11 ll. 10-13; Snider Direct, p. 14, ll. 2-5) is nonsensical, because 1) Cherokee conveyed the necessary information to Duke in order to establish its LEO (to the extent that Duke did not already have that information based on the ongoing relationship between the parties); and 2) Duke never made available any "correct" form for Cherokee to use. In submitting our LEO materials, we had asked if Duke needed any other information or had any other form we were to use, and they never asked for further information or pointed us to another form. However, without a form or PSC approved

6 *See FLS Energy, Inc.*, 157 FERC ¶ 61,211 (2016) ("We find that, just as requiring a QF to have a utility-executed contract, such as a PPA, in order to have a legally enforceable obligation is inconsistent with PURPA and our regulations, requiring a QF to tender an executed interconnection agreement is equally inconsistent with PURPA and our regulations. **Such a requirement allows the utility to control whether and when a legally enforceable obligation exists – e.g., by delaying the facilities study or by delaying the tendering by the utility to the QF of an executable interconnection agreement. Thus, the Montana Commission's legally enforceable obligation standard is inconsistent with PURPA and our regulations under PURPA.**") See Also [2019 PSC order] at p. 146 ("We agree with witness Levitas that obtaining permits and land-use approvals prior to establishing a LEO is unreasonable, since this process is clearly expensive and time-consuming, and would come at a time that the QF has not secured a price for its output, and the QF would therefore lack financing.")

7 *Id.*

process for us to create a LEO, Duke still must abide by PURPA and recognize the substance of a LEO as of the date submitted by Cherokee.

Accordingly, without clear direction from Duke's website or a documented LEO process, and consistent with our prior course of dealings, we established a LEO by 1) contacting Duke regarding our expiring PPA term noticing Duke of our intent to put our power to Duke for a new contract term, and 2) filling out every available form that Duke made available for good measure, even though it asked for information that Duke already had. We formed this LEO far enough in advance such that Duke could avoid capacity additions by planning to take power from Cherokee. Cherokee cannot be faulted or penalized for trying to facilitate Duke's review of our LEO, by using a form that Duke itself had issued and tailoring that form to provide relevant information.

Q. HAS DUKE AT ANY POINT OFFERED CHEROKEE A CONTRACT CONSISTENT WITH PURPA REQUIREMENTS?

A. As I explained in my direct testimony, and contrary to Duke Witness Snider (Direct pp. 17-32) and Duke Witness Freund (Direct pp. 4-11), no it has not. While Duke has not been sufficiently cooperative in providing data to allow us to calculate Duke's avoided costs with precision, as discussed by Cherokee Witness Strunk it is apparent that Duke has offered us avoided cost rates below what we are entitled to under PURPA. By failing to calculate avoided costs based on our LEO date (including the capacity payment in effect for other QFs at the time) and offer us a PPA we could reasonably execute, Duke has frustrated our efforts to both acknowledge our LEO generally on a non-contractual basis and to enter into any kind of reasonable contractual arrangement under a PPA. This is why Cherokee must hold Duke to its non-contractual LEO. As I show in Table 1 below, each of Duke's offers was deficient and did not comply with Duke's obligations under PURPA.

Table 1: Timeline of Offers

Date	Offered by	Deficiencies
October 31, 2018	Duke Energy Carolinas	– Did not appropriately take into account the dispatchability of the Cherokee facility. – Discriminatory; did not provide compensation for avoided capacity costs. (See Strunk Rebuttal, p.11). – Inconsistent with Order 2016-349 and FERC's Implementing Regulations. (See Strunk Rebuttal).
February 1, 2019	Duke Energy Progress	– The transmission arrangements were not offered in a manner consistent with DEC and DEP's merger commitments. – Did not appropriately take into account the dispatchability of the Cherokee facility.
June 24, 2020	Duke Energy Progress	– Included avoided cost rates, but on terms that ran contrary to those approved in Order 2020-315(A). – Offered a form PPA appropriate for a solar QF and inappropriate for a dispatchable facility like Cherokee. – Disputed the establishment of a LEO.
December 15, 2020	Duke Energy Carolinas	– Offered an "as available" contract. – Failed to provide contract rates until after the delivery of energy to Duke such that Cherokee would have no idea whether its plant would be economic to run.
February 10, 2021	Duke Energy	– Apparently took dispatchability into account, but: – Avoided energy costs were not aligned with the Cherokee LEO date. – Avoided capacity costs were not aligned with the Cherokee LEO date.

Q. DO YOU BELIEVE THAT DUKE IS OBLIGATED TO OFFER CHEROKEE HIGHER THAN AVOIDED COST RATES TO SUSTAIN CHEROKEE'S FINANCIAL VIABILITY AS WITNESS BOWMAN (DIRECT P. 9, LL. 11-13) AND WITNESS KEEN (DIRECT P. 9, LL. 6-20) CLAIM?

A. No, these witnesses are mistaken, and I have never represented that. I explained in my direct testimony certain business background and how we use our revenues; I never said or implied that the calculation of avoided costs incorporated any consideration of Cherokee's needs. However, the failure of Duke to honor its statutory PURPA rights is damaging to Cherokee's business, which is grounded in the economic regulation of PURPA, and shows that Duke's failure to negotiate in good faith (as required by this Commission) has harmed Cherokee.

Q. DUKE'S WITNESSES REPEATEDLY REFER TO YOUR TERM SHEETS AS "UNSOLICITED." DOES THAT LESSEN DUKE'S OBLIGATIONS UNDER PURPA?

A. No. South Carolina requires that large cogeneration QFs negotiate with utilities for PPA terms—that is precisely what we tried to do.

Q. DO YOU AGREE WITH WITNESS SNIDER'S ANALOGY (DIRECT P. 15, ll. 2-10) THAT CHEROKEE'S EFFORTS WERE SIMILAR TO COMMITTING TO SELL A CAR TO TWO DIFFERENT USED CAR DEALERSHIPS?

A. No, the analogy fails and in fact demonstrates that Duke is not credible to represent that it negotiated with us in good faith. The proposition that "Cherokee appears to have toggled back and forth between the Companies to see where it could get a better deal" (Snider Direct p. 15, ll. 1-2) is refuted by the fact that Cherokee sent both its LEOs to Mr. Keen (who as described in his Direct Testimony works for both DEC and DEP). Accordingly, both DEC and DEP were completely aware of Cherokee's intent—that is, to allow Duke the maximum flexibility to most economically serve its customers with Cherokee's output. In fact it was Mr. Keen who suggested that DEP had a nearer term capacity need and suggested Cherokee file a LEO with DEP. Cherokee was indifferent to DEP or DEC, and was looking to supply Duke in a manner that would provide them the most flexibility. Further, as established in my direct testimony, FERC clearly permits QFs to split its output among different offtakers—FERC very recently recognized that there are situations where a "utility interconnecting a QF does not purchase all of the QF's output and instead transmits the QF power in interstate commerce," including where the "QF sells, plans to sell, or has the express right to sell to any of its output to an entity *other than* the utility directly interconnected to the QF."[8] Unlike a car, Cherokee's output is a commodity measured in MW units, and I can offer some units to one offtaker, and other MWs to another. However, one would not sell the engine of one's car to one dealership, and the body of one's car to another. The suggestion of duplicity or lack of intent to put power to Duke due to the "double LEO" defies common sense given the nature of the product for sale. It is not as though I made a promise to one car dealer, took their money, and walked across the street to sell it to another as Mr. Snider suggests. Additionally, Witness Bowman (Direct p. 24, ll. 1-7) takes certain comments Cherokee has made to FERC completely out of context—in no way does Cherokee's maintenance of its tariff to sell at market-based rates undercut Cherokee's offer to Duke—it only maintains third-party non-PURPA sales as an option (for example, in the event of Duke refusing to

[8] *See Cherokee County Cogeneration Partners, LLC,* 175 FERC 61,002, at P 17 (2021).

contract with Cherokee).

Q. DID DUKE NEGOTIATE IN GOOD FAITH TO ALLOCATE CHEROKEE'S ENERGY AND CAPACITY IN A WAY THAT WOULD BEST SERVE DUKE'S CUSTOMERS?

A. No, although we gave them every opportunity, including the option to put all or part of Cherokee's output to DEP. DEP was actively soliciting proposals to meet a capacity need beginning in December of 2020. At various times during negotiations, Duke postured that QFs were not eligible to be designated as "network resources" for transmission, and that we would be required to take "point-to-point" service to deliver our power to DEP. Duke's reaction is especially puzzling given that; in my experience, it is not at all uncommon for utilities to designate QFs as network resources. See Table 2 below (and Exhibits 1-3) for a number of examples:

Table 2: Example QF Network Resource Designations

Transmission Provider	**Qualifying Facilities Designated as Network Resources**
Southern Companies (See Ex. 1 Designated Network Resource List)	– FERC Docket No. QF12-120 – Coca-Cola QF – FERC Docket No. QF18-188 – GRP Madison, LLC – FERC Docket No. QF16-755 – Old Midville Solar – FERC Docket No. QF15-439 – Rincon Solar
Public Service Company of New Mexico (See Ex. 2 Designated Network Resource List)	– FERC Docket No. QF19-927 – Vista SEC – FERC Docket No. QF20-575 – Britton Solar Energy Center
Southwest Power Pool (See Ex. 3 Designated Network Reource List)	FERC Docket No. QF08-148 – Sleeping Bear, LLC FERC Docket No. QF03-11 – Blue Canyon

Further, since Cherokee is a dispatchable facility, it most naturally fits with the network "integration" service that DEC and DEP offer under their OATTs. Cherokee is not offering a block energy product that is delivered from a single source bus to one sink. Rather, similar to the other DEP network resources that DEP uses to serve its network load, the Cherokee resource assists Duke to serve native loads at many delivery points under an integrated approach to dispatch. Point-to-point transmission does not fit the model under which Cherokee has been dispatched by DEC under its joint dispatch arrangements with DEP. Under a dispatchable tolling agreement scenario—the most economic option for Duke to structure its offtake—Cherokee would not know in advance whether DEP would call on it to run, and it would not have knowledge of DEP's preferred point of delivery. It would be unduly burdensome, discriminatory, and expensive to expect Cherokee to make point-to-point arrangements across DEC's system to DEP, as though DEC and DEP were two completely unrelated utilities, instead of affiliated companies operating under a Joint OATT that allows for non-pancaked deliveries of power between DEP and DEC. Such an arrangement would not make the most prudent use of Cherokee's output as Duke should be expected to do for its customers.[9] To be clear, Cherokee has never represented that it expected network service arrangements to be free—Cherokee would gladly pay any reasonable incremental costs associated with appropriate, non-discriminatory network service transmission to accomplish the arrangements.

Q. WHY DID CHEROKEE EVEN CONSIDER SELLING ITS OUTPUT TO DEP WHEN IT IS INTERCONNECTED TO DEC?

A. In discussions with DEC, we had confronted them about not providing us with a capacity payment, despite their having a capacity need. DEC indicated that it did not recognize the capacity need on its own system until 2028. However, Duke pointed us to DEP as having a capacity need sooner, and so we pursued that route in a good faith effort to negotiate as South Carolina prefers. Rather than facilitate transmission to accomplish a sale to DEP, as one would expect if Duke were negotiating in good faith; it now faults us for engaging with DEP—Duke's own suggestion—to try to deprive us of our LEO right under PURPA, and impose unreasonably onerous requirements that would require Cherokee to procure point-to-point transmission where DEP could easily designate Cherokee as a network resource at no incremental cost to its customers.

[9] As I explained in my direct testimony (p.18, ll. 4-13 and n. 10), it is apparent that Cherokee satisfies the definition of Network Resource under section 1.37 of DEP's OATT.

Q. WOULD YOU BE BURDENING DUKE'S RATEPAYERS BY BEING DESIGNATED AS A NETWORK RESOURCE, AS WITNESS BOWMAN ALLEGES (DIRECT P. 36, LL. 14-21)?

A. No. As I discussed in my Direct Testimony, such a designation is contemplated by Duke's representations in its merger application and the Joint OATT; and is further supported by Duke's Business Practice Manual.[10] Witness Bowman faults Cherokee for not submitting a transmission service request to reserve transmission for transfer to DEP. However, for network transmission service, it would be the Network Customer—DEP—who would designate Cherokee as a network resource to serve DEP's network load. Cherokee does not have the ability to unilaterally designate a DEP network resource. However, if the Commission directs DEP to purchase all or a portion of Cherokee's power; designation of Cherokee as a network resource is an immediate, flexible way to implement the Commission's directive that does not involve excessive transmission charges to Cherokee or disregard of Duke's merger commitments.

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[10] *See e.g.*, Duke Energy Progress, LLC's OASIS Business Practice, Section E, p. 45 (effective 06/01/2021) *available at* http://www.oatioasis.com/cpl/; https://www.oasis.oati.com/woa/docs/CPL/CPLdocs/DEP_Business_Practices_effective_06-01-2020_posted_05-18-2020_-_CLEAN.pdf ("The Joint OATT provides for a zonal rate structure for transactions involving more than one of the Duke Energy Carolinas (DEC), Duke Energy Progress (DEP) and/or Duke Energy Florida (DEF) transmission systems. Under the zonal rate structure, transmission customers who use only one of the zones will pay the rate applicable to that zone. The customer will be charged only the rate for the zone in which the load is located or from which the power is removed from the system. For example, a Network Customer using PTP or NITS to serve load located in a different zone pays only the applicable charge in the zone where the load is located")

Q. WITNESS BOWMAN SUGGESTS (DIRECT PP. 20-21) THAT FERC'S ORDER NO. 872 REQUIRES THAT CHEROKEE DEMONSTRATE ITS FINANCEABILITY TO THE REGULATORY AUTHORITY AS A PRE-REQUISITE TO SECURING A LEO. IS THAT ACCURATE?

A. No. Witness Bowman misstates Order no. 872 (O.872) in this regard. That rule explicitly applies to new QFs in development, not existing QFs. (O.872 at P 684). The rule stated that QFs already in operation *have necessarily* demonstrated a commitment to construct the project, the Commission stated that it did not intend commercial viability and financial commitment requirements to serve as prerequisites to QFs already in operation with existing LEOs to obtaining new LEOs." O.872 at n. 995.

Q. DID O.872 UNDERCUT A QF'S ABILITY TO LOCK IN AVOIDED COST RATES THROUGH A LEO?

A. No. It is ironic that the Duke witnesses, including Bowman (Direct, p. 21) and Snider (Direct, p. 9) seek to use O.872 to try to obstruct our LEO. In discussing this viability requirement, FERC explained that "[t]he objective and reasonable criteria we have established will protect QFs against onerous requirements for a LEO that hinder financing, such as a requirement for a utility's execution of an interconnection agreement or power purchase agreement, **or requiring that QFs file a formal complaint with the state commission**, or limiting LEOs to only those QFs capable of supplying firm power, or requiring the QF to be able to deliver power in 90 days." (O.872 at P 689) (Emphasis added). That bolded point is precisely what Witnesses Snider and Bowman suggest—that our right to a LEO must be established by the PSC only after our complaint and a demonstration that it has exhausted all options with Duke. However, such action by a state would be plainly impermissible under PURPA.

Q. WHAT WOULD YOU HAVE EXPECTED DUKE WOULD HAVE DONE IN GOOD FAITH NEGOTIATIONS?

A. As I have stated previously, Duke's frustration of our rights centers around its flat refusal to acknowledge that we have LEO rights, and to calculate avoided costs based on that that LEO. Consistent with our prior course of dealings, I would have expected Duke to control costs for its customers by entering into a tolling agreement structure (like the structure it finally offered in 2021 as Witness Strunk describes), in 2018 rather than force discussions using the structure they use for solar PPAs that don't have fuel requirements. A solar offtake PPA is inappropriate for a highly dispatchable, efficient natural gas cogeneration resource with variable fuel costs like Cherokee. Duke knows this, and though it ultimately acquiesced in 2021(several years into negotiations) to a structure that has served both parties well under the existing PPA, it has yet to offer us this structure with appropriate avoided energy costs or capacity payments based on our LEO date.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TESTIMONY AND THE RELIEF CHEROKEE IS SEEKING FROM THE COMMISSION.

A. Certainly. Duke recognizes that it is the QF's option, not the utility's, to have the avoided cost rate calculated (i) based on projections of avoided costs as of the LEO date for the contract term, or (ii) at the time of the delivery of the QF's power (see Bowman Direct, p. 19; Snider Direct, p. 15). However, Duke's tactics have undercut our ability to have the avoided cost rates based on when the LEO was established in 2018. The discussions should have involved the proper calculation of the avoided cost rate in 2018, as well as the projected future avoided cost rates based on the data and assumptions in 2018.

Instead, as I noted previously about the lack of good faith negotiations, Duke 1) failed to provide us with sufficient supporting data for the avoided cost rate that they provided; 2) dragged out the process for over 2 years; 3) raised impediments to transmission service that do not exist; and 4) now quote current avoided cost rates, not the avoided cost rates projected at the time our LEO was established. So while Duke recognizes the clear PURPA options that rest with the QF, not the utility, they have disregarded our LEO rights and are offering current rates at the time of delivery, which was not the option we selected. From a policy standpoint, if Duke continues to proceed in this manner with other QFs, I expect that Duke's tactics will lead to more complaints; or worse for customers, facilities being retired before they ought to be from an economic standpoint. Cherokee requests that this Commission direct Duke to offer us a 10-year PPA under a tolling agreement structure like that Duke finally offered to Cherokee in January 2021, but to revise the contract price to match Duke's avoided costs as of September 2018, as Witness Strunk describes.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Exhibit One to Hanson Rebuttal Testimony

Southern Company

Southern Company's Designated Network Resources for 2021

Resource Name	Geographical Location	Electrical Location	Total Installed Capacity (kW)		Capacity Designated as Network Resource (kW)	
			Summer 2021	Winter 2021-22	Summer 2021	Winter 2021-22
Resources Owned and/or Operated by Southern Companies						
BANKHEAD DAM	Tuscaloosa County, AL	Southern BAA	56,000	56,000	56,000	56,000
BARRY	Mobile County, AL	Southern BAA	2,399,800	2,431,400	2,399,800	2,431,400
BARTLETT'S FERRY DAM	Harris County, GA, Chambers & Lee County, AL	Southern BAA	189,700	189,700	189,700	189,700
BOULDIN DAM	Elmore County, AL	Southern BAA	226,000	226,000	226,000	226,000
BOULEVARD	Chatham County, GA	Southern BAA	14,000	18,600	14,000	18,600
BOWEN	Bartow County, GA	Southern BAA	3,232,000	3,232,000	3,073,000	3,232,000
BURTON DAM	Rabun County, GA	Southern BAA	9,500	8,700	9,500	8,700
CHEVRON	Jackson County, MS	Southern BAA	135,000	150,000	135,000	150,000
DANIEL	Jackson County, MS	Southern BAA	1,594,000	1,648,000	1,594,000	1,638,000
FARLEY	Houston County, AL	Southern BAA	1,799,000	1,799,000	1,799,000	1,799,000
FLINT RIVER DAM	Dougherty & Lee County, GA	Southern BAA	6,500	6,500	6,500	6,500
FORT BENNING SOLAR	Russell County, AL	Southern BAA	30,000	30,000	30,000	30,000
FORT GORDON SOLAR	Richmond County, GA	Southern BAA	30,000	30,000	30,000	30,000
FORT STEWART SOLAR	Liberty County, GA	Southern BAA	30,000	30,000	30,000	30,000
FORT VALLEY SOLAR	Peach County, GA	Southern BAA	11,000	11,000	11,000	11,000
GADSDEN	Etowah County, AL	Southern BAA	130,000	130,000	130,000	130,000
GASTON	Shelby County, AL	Southern BAA	1,887,000	1,890,728	1,836,837	1,836,5[illegible]
GOAT ROCK DAM	Harris County, GA & Lee County, AL	Southern BAA	38,800	39,500	38,800	39,500
GREENE COUNTY	Greene County, AL	Southern BAA	1,272,100	1,416,100	1,272,100	1,416,100
HARRIS DAM	Randolph County, AL	Southern BAA	133,000	133,000	133,000	133,000
HATCH	Appling County, GA	Southern BAA	1,759,000	1,808,000	881,259	905,80[illegible]
HENRY DAM	St. Clair & Talladega County, AL	Southern BAA	71,000	71,000	71,000	71,000
HOLT DAM	Tuscaloosa County, AL	Southern BAA	48,000	48,000	48,000	48,000
JORDAN DAM	Elmore County, AL	Southern BAA	136,000	136,000	136,000	136,000
KINGS BAY SOLAR	Camden County, GA	Southern BAA	30,161	30,000	30,161	30,000
LAY DAM	Chilton & Coosa County, AL	Southern BAA	182,000	182,000	182,000	182,000
LLOYD SHOALS DAM	Jasper, Butts, Newton, & Henry County, GA	Southern BAA	22,500	20,900	22,500	20,900
LOGAN MARTIN DAM	St. Clair & Talladega County, AL	Southern BAA	135,000	135,000	135,000	135,000
LOWNDES COUNTY COGEN	Lowndes County, AL	Southern BAA	92,000	102,000	92,000	102,000
MARINE CORPS LB	Dougherty County, GA	Southern BAA	31,000	31,000	31,000	31,000
MARTIN DAM	Elmore & Tallapoosa County, AL	Southern BAA	186,000	186,000	186,000	186,000
MCDONOUGH	Cobb County, GA	Southern BAA	2,484,000	2,732,000	2,484,000	2,732,000
MCINTOSH	Effingham County, GA	Southern BAA	1,979,600	2,130,000	1,979,600	2,130,000
MCMANUS	Glynn County, GA	Southern BAA	414,000	513,000	414,000	513,000
MILLER	Jefferson County, AL	Southern BAA	2,782,800	2,782,800	2,669,719	2,669,7[illegible]
MITCHELL DAM	Chilton & Coosa County, AL	Southern BAA	166,000	166,000	166,000	166,000
MOODY AFB SOLAR	Lowndes County, GA	Southern BAA	48,000	48,000	48,000	48,000
MORGAN FALLS DAM	Fulton & Cobb County, GA	Southern BAA	10,570	11,100	10,570	11,100
NACOOCHEE DAM	Rabun County, GA	Southern BAA	6,000	6,000	6,000	6,000
NORTH HIGHLANDS DAM	Harris County, GA & Lee County, AL	Southern BAA	34,400	34,700	34,400	34,700
OLIVER DAM	Muscogee County, GA & Lee County, AL	Southern BAA	59,200	58,200	59,200	58,200
RATCLIFFE	Kemper County, MS	Southern BAA	699,000	765,000	699,000	765,000
ROBINS AFB SOLAR	Houston County, GA	Southern BAA	128,000	128,000	128,000	128,000
ROCKY MOUNTAIN	Floyd County, GA	Southern BAA	1,050,000	1,050,000	266,595	266,595
SCHERER	Monroe County, GA	Southern BAA	2,365,000	2,365,000	728,701	728,681
SINCLAIR DAM	Baldwin, Putnam, Hancock, & Jones County, GA	Southern BAA	43,800	43,800	43,800	43,800
SMITH DAM	Walker County, AL	Southern BAA	180,000	180,000	180,000	180,000
SWEATT	Lauderdale County, MS	Southern BAA	32,000	41,000	32,000	41,000
TALLULAH DAM	Rabun & Habersham County, GA	Southern BAA	72,900	72,900	72,900	72,900
TERRORA DAM	Rabun County, GA	Southern BAA	16,600	16,600	16,600	16,600
THEODORE COGEN	Mobile County, AL	Southern BAA	231,000	245,000	231,000	245,000
THURLOW DAM	Elmore & Tallapoosa County, AL	Southern BAA	81,000	81,000	81,000	81,000
TUGALO DAM	Oconee County, SC, Rabun & Habersham County, GA	Southern BAA	52,320	52,400	52,320	52,400
VOGTLE	Burke County, GA	Southern BAA	2,302,000	3,539,000	1,078,139	1,648,198
WALLACE DAM	Hancock, Putnam, Morgan, & Greene County, GA	Southern BAA	330,808	330,844	330,808	330,844

Updated: 5/14/202

Southern Company

Southern Company's
Designated Network Resources for 2021

Resource Name	Geographical Location	Electrical Location	Total Installed Capacity (kW)		Capacity Designated as Network Resource (kW)	
			Summer 2021	Winter 2021-22	Summer 2021	Winter 2021-22
WANSLEY	Heard County, GA	Southern BAA	1,744,000	1,744,000	933,040	933,040
WARNER ROBINS	Houston County, GA	Southern BAA	160,000	186,000	160,000	186,000
WASHINGTON CO COGEN	Washington County, AL	Southern BAA	100,000	107,000	100,000	107,000
WATSON	Harrison County, MS	Southern BAA	817,000	825,200	817,000	825,200
WEISS DAM	Cherokee County, AL	Southern BAA	81,000	81,000	81,000	81,000
WILSON	Burke County, GA	Southern BAA	295,000	364,000	295,000	364,000
YATES	Coweta & Carroll County, GA	Southern BAA	714,000	714,000	648,641	648,641
YATES DAM	Elmore & Tallapoosa County, AL	Southern BAA	47,000	47,000	47,000	47,000
YONAH DAM	Oconee County, SC, Stephens & Habersham County, GA	Southern BAA	28,500	28,701	28,500	28,70[illegible]
			35,471,559	37,715,373	29,751,690	31,449,[illegible]2
System Sales that have been designated as Network Resources on the same transmission system by the buyer						
System Capacity Allocation from Alabama Power Company resources as described in the Power Supply Agreement between APC and AEC.					-300,000	-300,000
System Capacity Allocation from Mississippi Power Company resources as described in the Power Supply Agreement between MPC and SMEPA.					-86,000	-86,000
System Capacity Allocation from Alabama Power Company resources as described in the Power Supply Agreement between APC and AMEA.					-550,000	-550,000
System Capacity Allocation from Alabama Power Company and Mississippi Power Company resources to serve SWE Contracts.					-156,000	-156,000
System Capacity Allocation from Georgia Power Company resources as described in the Power Supply Agreements between GPC and Flint.					-55,337	-55,337
					-1,147,337	-1,147,337
Independent Power Producers (IPP) & Other Sources						
ADDISON	Upson County, GA	Southern BAA	305,450	336,000	292,953	336,000
ALBANY RENEWABLE ENERGY	Dougherty County, GA	Southern BAA	49,500	49,500	49,500	49,500
ANNISTON ARMY DEPOT	Calhoun County, AL	Southern BAA	7,400	7,400	7,400	7,400
BLUE CANYON	Caddo & Commanche Counties, OK	MISO BAA	100,000	100,000	100,000	100,000
BUFFALO DUNES	Finney, Grant, & Haskell Counties, KS	SPP BAA	202,000	202,000	202,000	202,000
BROKEN SPOKE SOLAR	Mitchell County, GA	Southern BAA	0	195,500	0	195,000
BUTLER SOLAR	Taylor County, GA	Southern BAA	100,000	100,000	100,000	100,000
BUTLER SOLAR FARM	Taylor County, GA	Southern BAA	20,000	20,000	20,000	20,000
CALHOUN POWER	Calhoun County, AL	Southern BAA	640,000	708,000	632,000	708,000
CAMILLA SOLAR ENERGY	Mitchell County, GA	Southern BAA	160,000	160,000	160,000	160,000
CAMILLA SOLAR PPA	Mitchell County, GA	Southern BAA	16,000	16,000	16,000	16,000
CHISHOLM VIEW	Garfield & Grant Counties, OK	SPP BAA	202,000	202,000	202,000	202,000
COCA-COLA QF	Fulton County, GA	Southern BAA	6,300	6,300	6,300	6,300
COOL SPRINGS SOLAR	Decatur County, GA	Southern BAA	0	213,000	0	213,000
DAHLBERG	Jackson County, GA	Southern BAA	376,175	376,175	371,389	445,000
DECATUR COUNTY SOLAR	Decatur County, GA	Southern BAA	19,000	19,000	19,000	19,000
DECATUR PARKWAY SOLAR	Decatur County, GA	Southern BAA	79,900	80,000	79,900	80,000
DOUGHERTY COUNTY SOLAR	Dougherty County, GA	Southern BAA	120,000	120,000	120,000	120,000
DUBLIN BIOMASS - GPS	Laurens County, GA	Southern BAA	29,000	29,000	29,000	29,000
FLINT RIVER	Macon County, GA	Southern BAA	24,750	24,750	24,750	24,750
FORT RUCKER SOLAR	Dale County, AL	Southern BAA	10,600	10,600	10,600	10,600
GRP FRANKLIN	Franklin County, GA	Southern BAA	72,000	72,000	58,000	58,000
GRP MADISON	Madison County, GA	Southern BAA	60,000	60,000	58,000	58,000
HATTIESBURG FARM	Forrest County, MS	Southern BAA	50,000	50,000	50,000	50,000
HARRIS	Autauga County, AL	Southern BAA	640,625	667,781	640,625	667,781
HEARD COUNTY	Heard County, GA	Southern BAA	965,550	965,550	945,000	945,000
HOG BAYOU ENERGY CENTER	Mobile County, AL	Southern BAA	222,000	244,000	222,000	244,000
LAFAYETTE SOLAR	Chambers County, AL	Southern BAA	80,000	80,000	80,000	80,000
LIVE OAK SOLAR	Candler County, GA	Southern BAA	51,000	51,000	51,000	51,000
MAS GA PINE RIDGE	Spalding County, GA	Southern BAA	6,300	6,300	6,300	6,300
MAS GA RICHLAND CREEK	Gwinnett County, GA	Southern BAA	10,500	10,500	10,500	10,500
MID GEORGIA COGEN	Houston County, GA	Southern BAA	300,000	300,000	300,000	300,000
MONROE POWER	Walton County, GA	Southern BAA	309,428	309,428	309,428	309,428
MS SOLAR 2	Lamar County, MS	Southern BAA	52,000	52,000	52,000	52,000
OLD MIDVILLE SOLAR	Jenkins County, GA	Southern BAA	20,000	20,000	20,000	20,000
PAW PAW SOLAR	Taylor County, GA	Southern BAA	30,000	30,000	30,000	30,000
PIEDMONT GREEN POWER	Lamar County, GA	Southern BAA	55,000	55,000	55,000	55,000

Southern Company

Southern Company's
Designated Network Resources for 2021

Resource Name	Geographical Location	Electrical Location	Total Installed Capacity (kW)		Capacity Designated as Network Resource (kW)	
			Summer 2021	Winter 2021-22	Summer 2021	Winter 2021-22
PORT WENTWORTH	Chatham County, GA	Southern BAA	27,700	22,770	27,700	22,770
QUITMAN SOLAR	Brooks County, GA	Southern BAA	150,000	150,000	150,000	150,000
QUITMAN II SOLAR	Brooks County, GA	Southern BAA	0	150,000	0	150,000
RINCON SOLAR CENTER	Effingham County, GA	Southern BAA	16,000	16,000	16,000	16,000
SIMON SOLAR PPA	Walton County, GA	Southern BAA	30,000	30,000	30,000	30,000
SR MERIDIAN III	Lauderdale County, MS	Southern BAA	52,500	52,000	52,500	52,000
TANGLEWOOD SOLAR	Mitchell County, GA	Southern BAA	57,500	57,500	57,500	57,500
TWIGGS COUNTY SOLAR	Twiggs County, GA	Southern BAA	200,000	200,000	200,000	200,000
WALTON COUNTY POWER	Walton County, GA	Southern BAA	465,212	465,212	465,212	465,212
WASHINGTON CO POWER	Washington County, GA	Southern BAA	312,872	312,872	312,872	312,872
WESTERVELT BIO	Hale County, AL	Southern BAA	6,000	0	6,000	0
WHITE OAK SOLAR	Burke County, GA	Southern BAA	76,500	76,500	76,500	76,500
WHITE PINE SOLAR	Taylor County, GA	Southern BAA	101,000	101,250	101,000	101,250
			6,887,762	**7,582,888**	**6,825,929**	**7,614,663**
			42,359,321	**45,298,262**	**35,430,282**	**37,916,419**

Notes:

[1]For Independent Power Producers (IPP) & Other Sources, Total Installed Capacity may reflect the contract capacity.

† For Jointly Owned Units (JOU), Total Installed Capacity includes amounts owned by parties other than Southern Company. JOUs include units at Hatch, Miller, Rocky Mountain, Scherer, Vogtle, Wansley.

In some cases, the difference between a plant's Installed Capacity and the Capacity Designated is the result of designation by other Load Serving Entities utilizing other Transmission Providers.

Designated Capacity shown above is not necessarily the basis for the dispatch of the 2020 Series Transmission Planning cases.

The Southern Company Designated Network Resource list is based on the rated capacity as of February 1, 2020 for each plant at the point of interconnection.

Southern Company

Southern Company's Designated Network Resources for 2021

Resource Name	Geographical Location	Electrical Location	Total Installed Capacity (kW) 2021	Capacity Designated as Network Resource (kW) 2021
Alabama Municipal Electric Authority (AMEA)				**820,000**
AMEA Sylacauga 1	Talladega County, AL	Southern Balancing Authority	47,500	47,500
AMEA Sylacauga 2	Talladega County, AL	Southern Balancing Authority	47,500	47,500
Block Purchase PPA between AMEA and Alabama Power Company.		Southern Balancing Authority	100,000	100,000
Block Purchase PPA between AMEA and Southern Power Company.		Southern Balancing Authority	25,000	25,000
Block Purchase PPA between AMEA and Santee Cooper.		Santee Cooper Balancing Authority	50,000	50,000
System Capacity Allocation from Alabama Power Company resources as described in the Power Supply Agreement between APC and AMEA.		Southern Balancing Authority	14,998,880	550,000
Note: The designated amount shown for System Capacity Allocation is also included as a Southern Company Designated Resource.				
City of Evergreen, AL (PINE)				
Power Purchase Contract for Full Requirements Electric Service between MEAG and PINE.		Southern Balancing Authority	11,000	Scheduled Real-Time
City of Hartford, AL (HART)				
Power Purchase Contract for Full Requirements Electric Service between MEAG and HART.		Southern Balancing Authority	8,000	Scheduled Real-Time
City of Robertsdale, AL (CRDL)				
Power Purchase Contract for Full Requirements Electric Service between MEAG and CRDL.		Southern Balancing Authority	24,000	Scheduled Real-Time
City of Troy, AL (COTR)				
Power Purchase Contract for Full Requirements Electric Service between CCG and COTR.		Southern Balancing Authority	100,000	Block Scheduled
Cooperative Energy (SME)				**1,475,000**
SMEPA's System Generating Resources located in the MISO Balancing Authority area that serve SME load in the Southern Balancing Authority.		MISO Balancing Authority	3,425,000	21[illegible],000
System Capacity Allocation from Mississippi Power Company resources as described in the Power Supply Agreement between MPC and SME.		Southern Balancing Authority	3,644,340	8[illegible],000
Power Supply Agreement between SEPA and SME.		Southern Balancing Authority	68,000	68,000
System Capacity Allocation from Mississippi Power Company resources under the MRA Cost Based Tariff.		Southern Balancing Authority	910,000	910,000
Supplemental System Capacity Allocation from Mississippi Power Company resources between MPC and SME.		Southern Balancing Authority	200,000	200,000
PowerSouth Electric Cooperative (AEC)				**413,081**
MILLER 1	Jefferson County, AL	Southern Balancing Authority	689,900	56,296
MILLER 2	Jefferson County, AL	Southern Balancing Authority	695,900	56,785
System Capacity Allocation from Alabama Power Company resources as described in the Power Supply Agreement between APC and AEC.		Southern Balancing Authority	14,998,880	300,000
Block Purchase PPA between AEC and Southern Power Company.		Southern Balancing Authority	200,000	200,000
AEC's Native Load Resources within the AEC Balancing Authority area that serve AEC load in the Southern Balancing Authority area.		AEC Balancing Authority		Scheduled Real-Time

Southern Company's Designated Network Resources for 2021

Southern Company

Resource Name	Geographical Location	Electrical Location	Total Installed Capacity (kW) 2021	Capacity Designated as Network Resource (kW) 2021
Southeastern Power Administration (SEPA)				
Allatoona Dam	Bartow County, GA	Southern Balancing Authority	102,000	Block Scheduled
Buford Dam	Forsyth County, GA	Southern Balancing Authority	150,000	Block Scheduled
Carters Dam	Murray County, GA	Southern Balancing Authority	620,000	Block Scheduled
Walter F. George Dam	Clay & Henry County, GA	Southern Balancing Authority	165,000	Block Scheduled
Hartwell Dam	Hart County, GA	SEPA Balancing Authority	426,000	Block Scheduled
Robert F. Henry Dam	Lowndes County, AL	Southern Balancing Authority	98,000	Block Scheduled
Millers Ferry Dam	Wilcox County, AL	Southern Balancing Authority	90,000	Block Scheduled
Richard B Russell Dam	Elbert County, GA	SEPA Balancing Authority	470,000	Block Scheduled
J. Strom Thurmond Dam	Columbia County, GA & McCormick County, SC	SEPA Balancing Authority	350,000	Block Scheduled
West Point Dam	Troup County, GA	Southern Balancing Authority	83,000	Block Scheduled
Total SEPA capacity designated for Southern Company's load and Network Customers per the *Agreement for Network Integration Transmission Service and Complementary Services between SEPA and SCS.*			**2,554,000**	**389,131**
Tennessee Valley Authority (TVA)				
TVA's Native Load Resources located in the TVA Balancing Authority area that serve TVA load in the Southern Balancing Authority area.		TVA Balancing Authority		Scheduled Real-Time
Southern Wholesale Energy (SWE)				**156,000**
System Capacity Allocation from Alabama Power Company resources to serve PowerSouth Electric Cooperative's **AEC Territorial Boundary.**		Southern Balancing Authority	14,998,880	3,000
System Capacity Allocation from Alabama Power Company resources to serve **Black Warrior Electric Membership Corporation** delivery points.		Southern Balancing Authority	14,998,880	114,000
System Capacity Allocation from Alabama Power Company resources to serve **Tombigbee Electric Cooperative** delivery points.		Southern Balancing Authority	14,998,880	39,000
Note: The designated amount shown for System Capacity Allocation is also included as a Southern Company Designated Resource.				

Updated: 5/14/202

Schedule of PNM Designated Network Resources (1 of 2)
October 6, 2020

Superseding July 2, 2020 Designated Network Resources

Generation [1]	Total Resource (MW)[3]	PNM Share %	PNM Share (MW)[3]	Comments
San Juan Unit 1	340	50%	170	
San Juan Unit 2	0	0%	0	
San Juan Unit 3	0	0%	0	
San Juan Unit 4	507	64%	327	
Total San Juan			497	
Four Corners Unit 4	787	13%	102	
Four Corners Unit 5	788	13%	102	
Total Four Corners			205	
Palo Verde Unit 1	1311	10.2%	133.7	
Palo Verde Unit 2	1314	10.2%	134.0	
Palo Verde Unit 3	1317	10.2%	134.3	
Total Palo Verde			402	
Reeves Unit 1	44	100%	44	
Reeves Unit 2	43	100%	43	
Reeves Unit 3	65	100%	65	
Rio Bravo Generating Station (formerly Delta-Person)[2]	148	100%	148	
La Luz Energy Center	40	100%	40	
Total Northern Metro Gas Resources			340	
Lordsburg Unit 1	40	100%	40	
Lordsburg Unit 2	40	100%	40	
Afton	236	100%	236	
Luna Energy Facility	564	33%	186	
Total Southern NM Gas Resources			502	

Schedule of PNM Designated Network Resources (2 of 2)
October 6, 2020
Superseding July 2, 2020 Designated Network Resources

Reeves Solar PV	2	100%	2	
Los Lunas Solar PV	7	100%	7	
Deming Solar PV	9	100%	9	
Alamogordo Solar PV	5	100%	5	
Las Vegas Solar PV	5	100%	5	
Manzano Solar PV	8	100%	8	
Otero County Solar PV	7.5	100%	7.5	
Meadowlake Solar PV	9	100%	9	
Sandoval Solar PV	6	100%	6	
Cibola Solar PV	8	100%	8	
Prosperity Energy Storage PV	0.5	100%	0.5	
Santolina Solar PV	10.5	100%	10.5	
Santa Fe Solar PV	9.5	100%	9.5	
South Valley Solar PV	10	100%	10	
Rio Communities Solar PV	10	100%	10	
Vista Solar Energy Center	10	100%	10	
Rio Del Oro Solar Energy Center	10	100%	10	
San Miguel 1 Solar Energy Center	10	100%	10	
San Miguel 2 Solar Energy Center	10	100%	10	
Rio Rancho Solar PV	10	100%	10	
Total Utility Scale Photovolatic Resources			147.0	
Purchases				**Expiration Date**
Valencia Energy Facility	158	100%	158	May 31, 2027
NextEra/FPL New Mexico Wind Energy Center	200	100%	200	September 16, 2043
Cyrq Lightning Dock Geothermal PPA	13	100%	13	March 10, 2042
Red Mesa Wind Energy Center	102	100%	102	December 31, 2034
Data Center 1 Solar Energy Center 1	10	100%	10	January 1, 2043
Data Center 1 Solar Energy Center 2	10	100%	10	March 1, 2043
Data Center 1 Solar Energy Center 3	10	100%	10	May 1, 2043
Casa Mesa Wind	50	100%	50	November 13, 2043
Britton Solar Energy Center	50	100%	50	December 13, 2044
Encino Solar Energy Center	50	100%	50	July 1, 2045
Total Purchases			653	
Total Generation & Purchases (MW)			2,746	
Expected New Generation (MW)				**Expected In-Service Date**
La Joya I Wind	166	100%	166	December 12, 2020
La Joya II Wind	140	100%	140	December 31, 2020
Jicarilla Solar II - Solar Direct Program	50	100%	50	March 31, 2021
Route 66 Solar	50	100%	50	December 1, 2021
Jicarilla Solar 1	50	100%	50	April 30, 2022
Jicarilla Storage 1	20	100%	20	April 30, 2022
San Juan Solar 1	200	100%	200	June 10, 2022
SJS 1 Storage	100	100%	100	June 10, 2022
Rockmont Solar	100	100%	100	June 20, 2022
Rockmont Storage	30	100%	30	June 20, 2022
Arroyo Solar	300	100%	300	June 30, 2022
Arroyo Energy Storage	150	100%	150	June 30, 2022
Total Expected New Generation	1,356	100%	1,356	

Notes:
(1) PNM participates in the Southwest Reserve Sharing Group (SRSG). This agreement provides back-up resources in the event certain PNM network resources are unavailable. These agreements,along with market purchases or other acquired generation resources, are periodically used as secondary resources but are not included in the list above.

(2) Rio-Bravo operating on natural gas.

(3) Resource capacities based on higher of summer or winter max tested ratings

Designated Network Resource list
for existing SPP NITS customers
Updated for service agreements filed through 7/21/2016.

Network Customer	Control Area of DNR	Name of DNR	Generation Unit Location County/State	Summer Maximum Net Dependable Capacity of DNR (MW)	Winter Maximum Net Dependable Capacity (MW)	Comments
American Electric Power	AEPW	Comanche1G1	Comanche County, OK	78	84	
American Electric Power	AEPW	Comanche1G2	Comanche County, OK	78	84	
American Electric Power	AEPW	Comanche1S	Comanche County, OK	117	117	
American Electric Power	AEPW	ComancheIC1	Comanche County, OK	4	4	
American Electric Power	AEPW	Dolet Hills	DeSoto County, LA	262	262	
American Electric Power	AEPW	Northeastern1	Rogers County, OK	429	475	
American Electric Power	AEPW	Northeastern2	Rogers County, OK	470	470	
American Electric Power	AEPW	Northeastern3	Rogers County, OK	460	460	
American Electric Power	AEPW	Northeastern4	Rogers County, OK	450	450	
American Electric Power	AEPW	NortheasternIC1	Rogers County, OK	4	4	
American Electric Power	AEPW	Riverside1	Tulsa County, OK	457	463	
American Electric Power	AEPW	Riverside2	Tulsa County, OK	460	465	
American Electric Power	AEPW	RiversideIC1	Tulsa County, OK	2.8	2.8	
American Electric Power	AEPW	Southwestern1	Caddo County, OK	78	80	
American Electric Power	AEPW	Southwestern2	Caddo County, OK	79	80	
American Electric Power	AEPW	Southwestern3	Caddo County, OK	315	315	
American Electric Power	AEPW	SouthwesternIC1	Caddo County, OK	2	2	
American Electric Power	AEPW	Tulsa2	Tulsa County, OK	165	165	
American Electric Power	AEPW	Tulsa4	Tulsa County, OK	165	165	
American Electric Power	AEPW	TulsaIC1	Tulsa County, OK	8.3	8.3	
American Electric Power	AEPW	Weleetka4	Okfuskee County, OK	55	65	
American Electric Power	AEPW	Weleetka5	Okfuskee County, OK	54	65	
American Electric Power	AEPW	Weleetka6	Okfuskee County, OK	54	65	
American Electric Power	AEPW	WeleetkaIC1	Okfuskee County, OK	4	4	
American Electric Power	AEPW	Arsenal Hill5	Caddo Parish, LA	110	110	
American Electric Power	AEPW	Flint Creek1	Benton County, AR	264	264	
American Electric Power	AEPW	Knox Lee2	Gregg County, TX	31	31	
American Electric Power	AEPW	Knox Lee3	Gregg County, TX	32	32	
American Electric Power	AEPW	Knox Lee4	Gregg County, TX	79	79	
American Electric Power	AEPW	Knox Lee5	Gregg County, TX	344	346	
American Electric Power	AEPW	Lieberman1	Caddo Parish, LA	25	25	
American Electric Power	AEPW	Lieberman2	Caddo Parish, LA	26	26	
American Electric Power	AEPW	Lieberman3	Caddo Parish, LA	110	115	
American Electric Power	AEPW	Lieberman4	Caddo Parish, LA	108	112	
American Electric Power	AEPW	Lone Star1	Morris County, TX	50	50	
American Electric Power	AEPW	Pirkey1	Harrison County,TX	580	580	
American Electric Power	AEPW	Welsh1	Titus County,TX	528	528	
American Electric Power	AEPW	Welsh2	Titus County,TX	528	528	
American Electric Power	AEPW	Welsh3	Titus County, TX	528	528	
American Electric Power	AEPW	Wilkes1	Marion County, TX	177	178	

American Electric Power	AEPW	Wilkes2	Marion County, TX	357	362	
American Electric Power	AEPW	Wilkes3	Marion County, TX	348	362	
American Electric Power	SWPA	SWPA Entitlements for Bentonville, AR Rayburn, TX and Minden, LA Power Energy Agreements with the Southwest Power Administration.		23	23	Term of service: 12/31/2009 to 12/31/2032 OASIS Ref# 73318258
American Electric Power	SWPA	SWPA Entitlement for Public Service Company of Oklahoma (PSO) Power Sales Contract between Southwestern Power Administration and American Electric Power		40	40	Term of service: 12/31/2009 to 12/31/2032 OASIS Ref# 73318265
American Electric Power	ERCOT	Oklaunion Unit No. 1 Construction, Ownership and Operating Agreement dated April 26, 1985. Network Resource in the ERCOT region scheduled over the Oklaunion HVDC Tie. PSO's allocation of the Oklaunion Power Station.	Oklaunion Power Station, Wilbarger County, TX	108	108	Term of service: 8/31/2005 to 1/1/2020
American Electric Power	ERCOT	Oklaunion Unit No. 1 Construction, Ownership and Operating Agreement dated April 26, 1985. Network Resources in the ERCOT region scheduled over the Oklaunion HVDC Tie. AEP Texas North Company's allocation of Oklaunion Power Station and SWEPCO's allocation of Southwest Mesa Wind Project executed February 12, 1998.	Oklaunion Power Station, Wilbarger County, TX Southwest Mesa Wind Project, Upton and Crockett Counties, TX	32	32	Term of service: 8/31/2005 to 1/1/2020
American Electric Power	AEPW	Minden LA Municipal Generation. Power Supply Agreement with the City of Minden Louisiana for SWEPCO to serve its load with rights to dispatch generation owned by the City of Minden. Agreement executed October 14, 2008.	Webster Parish, LA	32	32	Term of service: 8/31/2005 to 1/1/2020 OASIS Ref# 970201
American Electric Power	EES	Cajun Electric Power Cooperative, Inc. Power Supply Agreement with SWEPCO		50	50	50MW firm transmission rights Term of Service: 12/1/2014 to 12/1/2019 OASIS Ref# 80327159
American Electric Power	AEPW	Weatherford Wind Energy Center. Power Purchase Agreement between Public Service Company of Oklahoma and FPL Energy Cowboy Wind, LLC dated April 8, 2005	Custer County, OK	4.1	4.1	4.1 MW of net dependable capacity with 41MW of firm transmission rights. Term of service: 8/31/2006 to 8/31/2016 OASIS Ref# 1162642

American Electric Power	AEPW	Southwestern Power Station Unit #4 and #5	Southwestern Power Station, Caddo County, OK.	168	168	84MW Net Dependable Capacity per generating unit. Term of service: 7/1/2008 to 7/1/2013 and is renewed from 7/1/13 to 7/1/32 OASIS Ref # 78039480
American Electric Power	AEPW	Renewable Energy Purchase Agreement for Wind Energy Resources between Public Service of Oklahoma and Sleeping Bear, LLC dated April 25, 2005	Harper County, OK	8	8	8 MW of net dependable capacity with 80MW of firm transmission rights. Term of service: 5/31/2008 to 5/31/2028 OASIS Ref# 1194917
American Electric Power	AEPW	Riverside Power Station Unit # 3 and #4	Tulsa County, OK	172	172	86MW Net Dependable Capacity per generating unit. Term of service: 5/31/2008 to 5/31/2028 OASIS Ref# 1087757
American Electric Power	AEPW	Harry D. Mattison Power Plant Power Station Unit #1-#4	Washington County, AR	320	320	320 MW of firm transmission rights Term of service: 10/31/2008 to 10/31/2033 OASIS Ref# 1554702
American Electric Power	AEPW	John W. Turk Power Plant	Hempstead County, AR	The lesser of 73.333 % of Plant Net Dependable Capacity or 455MW	The lesser of 73.333 % of Plant Net Dependable Capacity or 455MW	455MW of firm transmission rights. Term of service: 3/31/2012 to 3/31/2032 OASIS Ref# 1525368
American Electric Power	AEPW	John W. Turk Power Plant	Hempstead County, AR	25	25	25 MW of firm transmission rights Term of service: 12/1/2014 to 12/1/2019 OASIS Ref# 80327126
American Electric Power	AEPW	J. Lamar Stall Power Plant	Caddo Parish, LA	455	550	Term of service: 5/31/2010 to 5/31/2035 OASIS Ref# 1525355, 1554704
American Electric Power	AEPW	J. Lamar Stall Power Plant	Caddo Parish, LA	54	54	Term of service: 5/31/2010 to 5/31/2015 OASIS Ref# 73482335
American Electric Power	WFEC	Balko Wind	Beaver Co., OK	0	0	200 MW firm transmission rights Term of Service: 1/1/2016 to 1/1/2036 OASIS Ref: 81052816
American Electric Power	WFEC	Blue Canyon Wind	Caddo County/Comanche County, OK	0	0	0 MW of net dependable capacity with 152MW of firm transmission rights. Term of service: 9/30/2009 to 9/30/2014 OASIS Ref # 73315204, 79136222
American Electric Power	WFEC	Blue Canyon Wind	Caddo County/Comanche County, OK	10.1	10.1	0 MW of net dependable capacity with 101 MW of firm transmission rights. Term of service: 7/31/2010 to 8/1/2030 OASIS Ref# 74485948
American Electric Power	AEPW	Dogwood	Cass Co, MO	80	80	Term of service: 6/1/2016 to 6/1/2021 OASIS Ref: 80780823
American Electric Power	AEPW	Eastman	Harrison County, Texas	40	40	Term of Service: 6/1/2016 to 6/1/2019 OASIS Ref# 80350819
American Electric Power	AEPW	Elk City Wind	Beckham County, OK	9.9	9.9	0 MW of net dependable capacity with 99 MW of firm transmission rights. Term of service: 7/31/2010 to 8/1/2030 OASIS Ref# 74485950